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Solid Expandable Tubular Technology – A Year of Case Histories in the Drilling Environment

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Abstract

Maximizing hole conservation while optimizing well economics in both conventional and deepwater wells is a continual challenge. Addressing these challenges with new technology has provided some significant solutions, but the uncertainty when utilizing new technology with no proven track record must be risk-weighted.

Solid Expandable Tubulars (SETs) have been installed in both openhole and cased-hole wellbores from November of 1999, in a variety of environments in wells on land, offshore and in deepwater to solve a range of drilling and completion challenges.

This paper will discuss the drilling case histories in depth including:

- Descriptions of drilling challenges surrounding the use of SETs and their next best alternatives
- Risk analysis leading to the use of SETs
- Discussion of the advantages and disadvantages of using SETs
- Operational lessons learned during installations of SETs

Technology Overview

Previously published papers and articles have discussed the concepts of Solid Expandable Tubular technology[1] and the effect of the expansion process on the system's tubulars[2, 3] and connectors[4]. In this paper, the basics of SET technology will be briefly reviewed, emphasizing how the early products of this new technology have been applied in the drilling environment. Presentation of several case histories will demonstrate that Solid Expandable Tubular products can provide additional tools for the drilling "tool box", ultimately cutting drilling costs and bringing more dollars to the bottom line. As of this writing, 15 jobs have been performed, of which three were unsuccessful. Since learnings often are the results of problems, heavy emphasis will be placed on problems and the lessons learned.

The Expansion System. The underlying concept of expandable casing is cold-working steel tubulars to the required size downhole - a process that, by its nature, is very unstable mechanically. Thus, there are many technical and operational hurdles to overcome when using cold-drawing processes in a downhole environment.

An expansion cone, or mandrel, is used to permanently mechanically deform the pipe **(Fig. 1)**. The cone is moved, or propagated, through the tubular by a differential hydraulic pressure across the cone itself and/or by a direct mechanical pull or push force. The differential pressure is pumped through an inner-string connected to the cone, and the mechanical force is applied by either raising or lowering the inner-string **(Fig. 2)**. The progress of the cone through the tubular deforms the steel beyond its elastic limit into the plastic region, while keeping stresses below ultimate yield **(Fig. 3)**. Expansions greater than 20 percent, based on the inside diameter of the pipe, have been accomplished. However, most applications using 4-1/4 inch to 13-3/8 inch tubulars have required expansions less than 20 percent.

At the bottom of the SET system is a canister, commonly known as the "launcher", that contains the expansion cone. The launcher is constructed of thin-wall, high-strength steel that has a thinner wall thickness than the expandable casing **(Fig. 4)**. Because the launcher has a thinner wall and its outside diameter (OD) is the same as the drift of the previous string of casing, it can be tripped into the hole through the previous casing string. The difference in the wall thickness of the launcher and the elastomer-coated hanger joint(s) allows the expanding pipe to be sealed, or "clad", to the previous casing string. The expanded pipe ends up with an outer diameter, after expansion, that is greater than the outer diameter of the launcher, while the inner diameter of the pipe expands to the same inner diameter of the launcher and the

expanded pipe.

Solid Expandable Tubular Products

Three expandable products have been developed, so far, using Solid Expandable Tubular Technology:

1. Expandable Openhole Liner System
2. Expandable Cased-Hole Liner System
3. Expandable Liner Hanger

While all three products have been discussed in previous papers, the Expandable Openhole Liner System will be the only expandable product discussed here.[5]

Expandable Openhole Liners. The expandable openhole liner (OHL) system is used to overcome operational challenges associated with borehole instabilities, pore pressure / fracture gradient issues, and the effects of salt or subsalt formations. All of these operational challenges produce the same end result -- pre-mature downsizing of a well's tubulars.

The system is run through existing casing or liner and is positioned in open hole, then expanded from the bottom up. When the expansion cone reaches the overlap between the expandable OHL and the existing pipe string, the cone expands a special hanger joint to provide a permanent seal between the two strings.

There are two reasons why the OHL system is expanded from the bottom up. The first reason is related to the shortening of the liner during expansion. Liners often are difficult to position at their planned total depth, and consequently may be positioned somewhat higher. A top-down expansion would first anchor the expandable liner in the previous pipe string, and the ensuing expansion would shorten the liner (approximately 4%) from the bottom up. The shortened, expanded liner then may not cover an adequate interval at the bottom of the hole. On the other hand, a bottom-up expansion first spots the expandable liner at its lowest depth, and the subsequent shortening experienced during the remaining expansion occurs in the overlap. Liner coverage at the bottom of the hole is thus ensured.

The second reason for using bottom-up expansion for an Expandable Openhole Liner is related to inner-string operations. It is easier to generate greater forces by pumping through and pulling on the inner-string than it is by adding weight to it. Because the inner-string already is being pulled out of the hole as a part of the bottom-up expansion operation, additional tensional forces can be added to the string, if necessary, to serve as a secondary force to drive the expansion. Whereas, with top-down expansion, any downward force or additional weight applied to the inner-string would serve as the secondary expansion force, placing the inner-string (drill pipe) in compression. Drill collars and heavyweight drill pipe would be needed as part of the inner-string to supply additional weight. This would only add time to inner-string makeup with minimal compressional forces being added in comparison to the tensional forces available. As a point of reference, propagation forces during expansion operations on 13-3/8 inch casing can approach 300,000 lbs. The size of the tubular and its mechanical properties typically determine the propagation forces required to expand it.

The installation steps for the Expandable Openhole Liner System are as follows (**Fig. 5**):

1. Drill hole section to facilitate the expandable liner installation
2. Run in hole with the expandable liner, expansion assembly and launcher
3. Cement expandable liner
4. Install latchdown plug to facilitate liner expansion
5. Expand Expandable Openhole Liner
6. Expand expandable liner's hanger joint
7. Drill-out expandable liner float shoe

Expandable Applications

Although expandable products are unique and very interesting in concept and in their installation, they have little value if cost-effective applications cannot be realized from their development. As is true of any new technology, expandable tubular products are not a panacea for all operational problems involving downhole tubulars. The economics of expandable tubular products must work for the long-term benefit of operators. As costs decline, the impact on all aspects of well operations is expected to increase dramatically.

Probably the most significant benefit of expandable technology is its "enabling" capacity. Currently, certain critical wells cannot be drilled to their objectives without solid expandable tubular technology. One example would be ultra-deepwater wells (over 5,000-ft water depth) where the operator uses every casing string available in the well design, yet the drilling environment requires more casing points than there are casing sizes.

The following five applications, or case histories, occurred in different drilling environments, including Gulf of Mexico shelf to ultra-deepwater areas and onshore U.S. They all represent significant downhole operational challenges that demanded the utmost mechanical, metallurgical and physical properties of the post-expanded tubulars.[6,7] The applications required expanded tubulars in lengths as long as 2,000 feet, with collapse ratings similar to conventional oilfield country tubulars and enough mechanical integrity to allow operators to drill through them once they were installed.

Gulf of Mexico (Shelf) Case History. The objective of the first commercial use of SET technology was to lower cost by decreasing casing and hole sizes compared to conventional technology. Halliburton Energy Services' Integrated Solutions group, working as lead contractor for Chevron USA Production Company on a Gulf of Mexico well in the West Cameron Block 17 field, successfully reached this objective in November 1999.[8,9] The conventional design and corresponding SET design using a 7-5/8 inch by 9-5/8 inch SET liner, are shown in **Figure 6**.

Prior to the actual offshore installation, a full-scale system test was performed on a test well onshore. This complete system test allowed training for the crews that were to install the system offshore and provided confidence that the system would perform as designed for the offshore application. The

test resulted in a design change to the float shoe assembly that would effect a more efficient drill-out with the mill assembly, as well as the determination of an optimum pump rate of ½ to ¾ barrel per minute (BMP) for expansion of the liner.

As is appropriate for the application of any type of new technology, a detailed contingency plan was developed to cover difficulties that might be encountered during the actual offshore installation. Once this plan was in place, all efforts could then be focused on a successful installation.

The 9-5/8 inch casing string originally comprised 53.5 pound per foot (ppf) casing joints. To allow the 7-5/8 inch by 9-5/8 inch hanger joint expansion to maintain the drift diameter of the expanded liner, the well design was changed so that the bottom four joints were 47.0 ppf casing joints. The actual internal diameters and wall thicknesses of these joints, at the interval the hanger joint would be expanded against, were carefully measured.

The hole interval below the 9-5/8 inch casing was drilled out to a slightly enlarged 9-7/8 inch diameter to allow for sufficient cement volume and annular clearance to expand the 7-5/8 inch by 9-5/8 inch SET liner. The cement volume was planned so that the top of the cement would be at the base of the 9-5/8 inch casing after the 7-5/8 inch by 9-5/8 inch SET liner was expanded. The hole interval was logged with a caliper to accurately measure hole diameter to finalize the cement volumes to be used.

The hole interval was drilled using a final 15.7 ppg mud weight, then a dummy run was made with a dummy launcher assembly to verify that the actual launcher assembly could be lowered through the casing, and that the open hole was not restricted. The latchdown plug was pumped and landed in a plug catcher to measure the actual volume required to pump the plug into place during the SET liner job.

A 985-foot length of 7-5/8 inch by 9-5/8 inch SET liner was run on a 3-1/2 inch by 5-inch tapered inner-string to a measured depth of 13,131 feet. The well was circulated and cement pumped, followed by the latchdown plug. Once the latchdown plug landed, the expansion process took about 4-1/2 hours, with pressures averaging 4,000 lbs/in.^{2}, and a maximum pressure of 4,800 lbs/in.^{2} when the hanger joint was expanded against the 9-5/8 inch casing. The initial liner length of 985 feet shortened to 946 feet, a result of the expansion process, putting the top of the SET liner at a measured depth of 12,185 feet.

The mill assembly was run into the well and the mud weight reduced to 12.5 ppg, providing a 2,165 lb/in.^{2} negative (collapse) differential test of the SET liner. The mud weight reduction was to allow drilling to proceed through the depleted sands expected to be encountered below the SET liner. The negative test was followed by a 3,500 lbs/in.^{2} positive pressure test. The float shoe assembly was drilled out, and a shoe squeeze performed after the initial shoe test failed. The shoe squeeze was the only contingency action required on the SET application.

Below the SET liner, an 8-1/2 inch diameter enlarged hole was drilled through the depleted sands, where a conventional 7-inch production liner was run. The top of this liner was placed above the top of the SET liner due to production loads anticipated that exceeded the design limits of the SET liner. The well was then drilled to total depth as planned, reaching all the geological objectives.

Economic Analysis/Lessons Learned. The initial estimated cost-savings for using SET compared to conventional technology was about $400,000. The actual savings were estimated at approximately $85,000. Eliminating the dummy run with the dummy launcher assembly and the shoe squeeze that was performed on this well, would improve the cost-savings to about $290,000. Other lessons learned that would decrease installation time should result in additional savings, pushing the cost-savings to the original $400,000 estimate.

Discussion of Deepwater Applications. Expandable casing technology can provide value in deepwater well engineering operations in two areas:

1. An enabling technology for low drilling margin conditions
2. A cost-effective solution in conjunction with smaller rigs in deepwater

As operations move into deeper water, drilling margins (the difference between pore pressure gradient and fracture-pressure gradient) become narrower (**Fig. 7**). This results in more casing strings required to drill to an equivalent depth below the mudline compared to a well drilled in a shallower water depth. In some cases, using conventional casing programs with an 18-3/4 inch BOP stack and a 21-inch OD drilling riser, well objectives cannot be reached with a sufficiently large hole size for evaluation and production operations. **Figure 8** illustrates a sample ultra-deepwater well, located in more than 5,000 feet of water, that reached its objectives by using a 13-3/8 inch by 16-inch SET system. SET technology can also be used to provide contingency casing deeper in the well.

Traditionally, as water depth has increased, the size of the drilling vessel and equipment capacities has increased. The size of the rig is affected by water depth, metocean condition designs, BOP and riser size. The well objectives and casing program determine the minimum BOP stack and riser size. The riser size affects the following systems on a drilling rig:

- Deck load
- Deck space
- Riser tensioner capacity
- Hoisting system capacity
- Mud system volumes
- Bulk volumes

The dynamic loads on the hoisting system during deployment / recovery or disconnect scenarios also increase as the riser size increases. If the riser size can be reduced, the over-all deck load and deck space requirements allow a smaller (lower cost) rig to be used for operations in deepwater. Existing SET technology allows a smaller wellbore to be drilled. **Figure 9** illustrates a comparison of a typical casing program with an 18-3/4 inch BOP system versus a slender well with a compact

rig using SET technology. Given existing rig market conditions, approximately $5.0MM savings can be achieved on a 60-day well. **Figure 10** shows a graphic representation of these savings.

An additional technical barrier to the use of small rigs in deepwater has been the positioning system. Most small rigs contain conventional catenary mooring systems rated for relatively shallow water depths. Recent technology development in pre-installed mooring system design and installation techniques now allow rigs to be moored in water depths greater than 8,000 feet.

Next generation SET systems may allow the equivalent of a "monobore" well to be drilled, whereby the same hole size is drilled from surface to total depth (TD). A monobore well opens up further cost-saving opportunities for an operator by allowing a slim wellbore to be drilled with a small vessel. **Figure 11** shows the progression from conventional well construction to slender wells with SET technology and on to monobore well technology.

Gulf of Mexico (Ultra-Deepwater) Case History. The objective of this first deepwater installation was to overcome low drilling margins. This installation was performed for BP/Vastar in the Mississippi Canyon at a water depth of 5,400 feet. The design called for a 7-5/8 inch by 9-7/8 inch SET liner system as shown in **Figure 12**. This installation was not successful but the learnings from the failure led to modifications that enhanced the reliability of this SET system.

The previous casing string of 9-7/8 inch 62.80 ppf was set at 11,999 feet, and the next hole section was drilled with a bi-center bit to provide a 9-7/8 inch hole size to install the 7-5/8 inch SET liner. The 2,095 foot (pre-expansion length) 7-5/8 inch liner was run to 13,791 feet with a 3-½ inch by 5-inch by 5-½ inch tapered string of drill pipe. Four tight spots were encountered while running the liner, requiring reciprocation and circulation in order to pass through.

[Note: All depths reference the position of the expansion assembly unless noted otherwise.]

The planned cementing program was pumped and the latchdown plug displaced to the shoe and seated, creating the sealed pressure chamber. Pressure was increased and expansion operations were started, utilizing the top drive with an initial propagation pressure of 4,100 psi. Average propagation pressure was 3,800 psi with a pump rate of ¾ BPM. At 12,598 feet, pressure dropped to 1,100 psi. No returns indicated pumping into the formation.

A connection at 12,604 feet was expanded just prior to the pressure loss. After the pressure dropped to 1,100 psi, the inner-string was lowered past the connection at 12,604 feet to ensure the connection was still intact enough to pass through. The inner-string was then lowered until the expansion cone set down on the next connector at 12,636 feet, thus confirming the relative location of the cone to the liner connections.

The cone was pulled back up to the expansion face at 12,598 feet, and the liner mechanically expanded to 12,565 feet (average of 150,000 lbs overpull). A drop in string weight indicated the liner had parted, leaving 1,200 feet of liner below the part. The string was slacked off to 12,542 feet, released from the latch assembly, then pulled up to 11,930 feet and circulated bottoms up. The cone was left on the expansion face while the rest of the inner-string was pulled to the liner top to ensure no cement was above the top of the liner. This also allowed the cement time to set up so another attempt could be made to mechanically expand the rest of the liner.

The inner-string was then lowered to engage the cone assembly at 12,542 feet. With the cone on the expansion face, 20 bbls were pumped down the annulus to ensure there was no cement in the 7-5/8 inch by 9-7/8 inch annulus. Next, a coiled-tubing unit was rigged up and 1-½ inch coiled tubing run inside the inner-string. The end of the tubing could not pass the end of the cone assembly. When pulled out of the hole, the bottom of the coiled-tubing tool string had markings on it, indicating it had set down on metal. The outside of the tool string was covered with what appeared to be gumbo.

An electric line unit was rigged up, a casing collar log (CCL) run. The logging tool set down at the bottom of the cone assembly. A string shot was then run, and the drillstring backed off just above the expansion cone assembly.

A mechanical casing cutter was run and the unexpanded section of the 7-5/8 inch liner cut. A casing spear fished the liner and expanded hanger out of the hole. A total of 569 feet of 7-5/8 inch unexpanded liner was recovered from the well. Sidetrack operations were initiated and drilling operations continued to objective.

Failure Cause Analysis. Detailed analysis was performed on:

1. the pressure, hookload and depth vs. time data from the rig's data acquisition system
2. visual and lab tests and analyses of the 569 feet of unexpanded casing and its connectors that had been recovered from the well
3. pre-job expandable casing properties and inspection data recorded before the job
4. torque-turn data
5. rigsite supervisor's notes.

The most likely failure cause was the jumping of the box after the pin nose seal leaked on connection No. 30 at 12,604 feet. Because the two liner sections were stuck when the connection separated, minimal longitudinal movement occurred. This allowed passage through the parted connector into the lower liner section during early operations, after pressure was lost.

Lessons Learned. Based on the findings of this analysis, several actions have been taken to minimize the chances of a recurrence of the events seen on the Mississippi Canyon well.

- Analysis of the unexpanded connectors recovered from the well indicated an "over-torqued" condition resulting in thread overrun. Thread design was reviewed and the 7-5/8 inch XPC thread design revised. All 7-5/8 inch liner in inventory was re-threaded to the revised thread design.
- Alternative makeup procedures, such as position makeup, are being investigated and a full-scale testing program designed.

- Research into the situation where the liner was stuck above and below the failed connector at the time of failure (fixed – fixed loading condition) is ongoing to gain a full understanding of the implications it would impose on the connector design.
- Modifications to the connector design would be implemented if research findings deem it necessary.
- The launcher has been redesigned to incorporate the float equipment internally, thus eliminating any possible pressure loading on the shoe during the expansion process and providing a more efficient drill-out operation.

South Texas Case History. The objective of the McAllen Ranch 106 installation was to isolate several pressure-depleted sands and minimize hole size reduction to TD **(Fig. 13)**. This installation was the first in a series of field trials Shell Exploration and Production Company is undertaking to test the technology in a lower risk environment prior to implementing it in higher-cost areas. This installation was not successful but the learnings from the failure led to modifications that enhance the reliability of SET systems in differentially-stuck conditions.

The previous casing string of 7-5/8 inch 33.70 ppf was set at 11,477 feet and the next hole section was drilled with a bi-center bit to provide a 7-1/2 inch hole size to install the 6-inch SET liner. The 785-foot (pre-expansion length) 6-inch expandable OHL system was made up, and run to 12,105 feet with a 3-½ inch by 5-inch tapered string of drill pipe. No tight spots were encountered while running the liner.

The liner became stuck at 12,097 feet, while reciprocating and circulating prior to cementing. The planned cementing program was pumped and the latchdown plug was displaced with 220 bbls, 40 bbls over displacement. The latchdown plug stopped in the 5-inch by 3-½ inch crossover, requiring the pump rate to be increased to four BPM to dislodge it. Expansion operations were begun at a propagation pressure of 4,200 psi, and continued in stands, with an average propagation pressure of 3,500 psi, with a ½ BPM pump rate. When the expansion cone reached a depth of 11,615 feet, pressure dropped to 400 psi, with returns at surface.

After pressure was lost, the expansion assembly was run to 11,566 feet, passing through the previously expanded connection with no obstruction. Then the expansion assembly was pulled back into the expansion face at 11,615 feet, where pumping into the drillstring resulted in circulation at ½ BPM, 150 psi, then at one BPM, 270 psi. The string was picked up to 300,000 lbs, 115,000 lbs over drillstring and liner weight, and it came free at a hookload of 200,000 lbs which indicated the full liner string. The string was picked-up six feet with a slight drag, then slacked back down to 11,615 feet.

Next, the string was pulled up into the expansion face and the safety joint released. The string was then pulled up above the top of the 6-inch liner at 11,312 feet, and circulated bottoms up to remove cement from the wellbore.

Wireline was rigged up and an ultrasonic-imaging tool logged from 12,064.5 feet up to 11,200 feet in an attempt to locate the failure. The expansion bottomhole assembly was located at 12,064.5 feet, the expansion face at 11,602 feet and the top of the unexpanded 6-inch liner at 11,301 feet.

A service packer was set at 11,590 feet and a temperature survey tool run while circulating to locate the depth of the failure. The survey indicated a severe temperature loss had occurred around the depth of the expansion face, 11,602 feet.

A mechanical casing cutter was then run-in to cut the unexpanded 6-inch liner at 11,590 feet. A casing spear retrieved 294 feet of the 6-inch unexpanded liner from the well.

Sidetrack operations were initiated and drilling operations continued to the objective.

Failure Cause Analysis. A detailed analysis of the log data on McAllen 106 well showed existence of several highly depleted (up to 6,000 psi) intervals. As mentioned earlier, the expandable liner became stuck while reciprocating and circulating prior to cementing. It is well known that pipe-sticking can occur during the running of casing, and often is attributed to differential sticking. Differential sticking occurs when the pipe becomes embedded in the filter cake opposite a permeable zone **(Fig. 14)**, held in place by the difference between hydrostatic pressure and formation pressure.[10]

Expanding a liner through a section that is differentially stuck dramatically changes the stress conditions created by the expansion cone in the pipe, can cause pipe damage and even rupture the expansion face. To reliably expand steel pipe beyond its elastic limit, it is necessary to maintain a displacement-controlled expansion process, and thus uniform hoop stress distributions on the expansion cone face **(Fig. 15a)**. If pipe is differentially stuck, this places geometrical constraints on the liner, drillstring and bottomhole assembly (BHA). If the magnitude of the differential pressure is small, the drill pipe and expansion cone will free up the stuck pipe and expansion can be continued safely. However, if the pressure differential is large enough, the liner cannot be freed. Geometrical constraints **(Fig. 16)** cause severe bending in the BHA and a large additional rotational moment is applied to the expansion cone **(Fig. 17)**. This moment causes concentration of hoop stress on the expansion face **(Fig. 15b)**, loss of displacement control and potential rupture of the liner.

Lessons Learned. It is believed that during expansion on the McAllen 106, the liner was ruptured due to severe differentially-stuck conditions. In a series of surface post-job expansion tests where these conditions were modeled, it was possible to reproduce and demonstrate the same mechanism of failure.

Modifications have been engineered to the standard BHA, which reduce the risk of becoming stuck, free up constrained pipe and/or enable expansion through the stuck interval without causing hoop stress concentration. Operational procedures have been revised to minimize this potential risk.

Field Validation and Testing for Implementation of an Ultra-Deepwater System. When implementing cutting-edge technology in 7,500 feet of water, extensive testing also is required to ensure that operational risk is minimized and

contingency plans are in place. In preparation for installation of Solid Expandable Tubulars in the ultra-deepwater environment, several tests had to be performed. These were comprised of laboratory expansion and pressure tests, surface expansion and pressure tests, and downhole expansion and pressure tests. Then the designated system needed to be installed in a test well to promote both familiarization with the system and a clear understanding of its installation procedures.

To that purpose, a commercial application of a 13-3/8 inch by 16 inch OHL as an extension of 16-inch conductor casing, was performed on Shell's Thomas-Rife 13 well in South Texas **(Fig. 18)**.[8]

The 2,016-foot (pre-expanded length) installation was set from a 2,300-foot well depth, using an expandable 13-3/8 inch 54.5 ppf casing expanded into 16-inch 84.0 ppf base casing. This represented a 12.8 percent expansion in diameter. Total job time was 48 hours.

The significance of this installation is that it provides the knowledge to operators planning ultra-deepwater wells that solid expandable tubulars are viable solutions in both planned and contingency installations. The SET systems shows in the center well plan in **Figure 11** further illustrate this point: an 11-3/4 inch by 13-3/8 inch system and a nested 9-5/8 inch by 11.614-inch system expanded into the expanded 11-3/4 inch by 13-3/8 inch system. This provides a 10.710-inch ID, allowing a conventional 9-5/8 inch full casing string to be run. Then a 7-5/8 inch by 9-5/8 inch expandable system can be installed in the well. The 7.973-inch inner diameter of this system allows a 7-inch flush joint string to be run through the expanded 7-5/8 inch by 9-5/8 inch system to TD the well.

Gulf of Mexico (Ultra-Deepwater) Case History. The objective of this ultra-deepwater installation was to overcome low drilling margins without sacrificing hole size. This installation was performed for Shell Exploration and Production Company at a water depth of 7,790 feet.

The previous casing string of 16 inch 84.0 ppf was set at 11,760 feet and the next hole section drilled with a bi-center bit to provide a 17-1/2 inch hole size to install the 13-3/8 inch SET liner. The 1,186-foot (pre-expansion length) 13-3/8 inch expandable OHL system was made up in eight hours. Three connections had to be broken out and remade due to perceived improper connection makeup; two joints were laid down because of galling. The liner was run to 12,647 feet with 5-1/2 inch drillstring. Two tight spots were encountered while running the liner; at 12,267 feet it took 15 to 20 kips to pass through the section and at 12,367 feet, 5 to 10 kips were required to get through. The liner was washed down to 12,684 feet, sixteen feet above TD.

The planned cementing program was pumped and the latchdown plug displaced with 310 bbls of 11.0 ppg PHPA mud. The drill pipe capacity was 280 bbls, indicating that fluid was bypassing the plug. The plug did not bump, the upper annular BOP closed, and 30 bbls were pumped at 16 BPM to place slurry into the formation. The latchdown plug apparently stopped within the bumper sub.

A second latchdown plug was installed and displaced with 263 bbls at 11.6 BPM with the upper annular BOP closed. The second plug dislodged the initial plug, which seated and pressured up to 5,200 psi. The rupture disk would not burst because the second plug was located across the disks, preventing pressure communication to them.

An attempt was made to stick the liner on-bottom and mechanically expand; however, the liner came free at 10 kips of overpull. The safety joint was rotated out and POOH. Fishing jars and drill collars were installed above the safety joint and run in the hole (RIH). After three attempts made to RIH failed due to fill, the safety joint was made-up into the expansion assembly and pressured up to 2,600 psi. After four hours of jarring on the expansion assembly attempting to open a flow path for pressure, the launcher expanded a sufficient distance to expose the rupture disks and gain pressure communication to the expansion cone. Pressure dropped from 2,695 psi to 1,261 psi. A coiled-tubing unit had been mobilized as an additional contingency to mill out the latchdown plug had the jarring operation been unsuccessful.

Expansion operations were started using the mud pumps and top drive, with an initial propagation pressure of 1,800 psi at 2.25 BPM. Expansion operations continued in stands, utilizing 85 to 100 percent of the liner weight on the hookload, reducing the pressures to 1,300 to 1,500 psi. No indication of differential sticking was observed during expansion across the sands. An increase of propagation pressure was seen when entering the 16-inch casing and additional force was required when expanding through the two 16-inch in-line centralizers positioned at 11,690 and 11,639 feet. All seven elastomer sections were apparent while expanding the hanger joint. Pressure was limited to 2,000 psi during expansion of the hanger joint, and additional overpull used to expand through. The "pop-out" was managed with a pump rate of 1 BPM at 1,400 psi, with 40 kips of overpull. This resulted in minimal energy release. Minimal surface indications were observed.

The liner top was tested to 1,000 psi for 10 minutes and again for 30 minutes while POOH above the BOPs. An additional 15-minute test at 2,000 psi was performed prior to the liner shoe squeeze operation.

Then a milling assembly, containing a 14.028-inch junk mill and a 14.028-inch watermelon mill, milled out the shoe assembly. Eleven and a half hours were required to mill out the extended shoe assembly. The mills then were pulled up to 12,480 feet, and a cement squeeze operation was performed.

Once the successful squeeze was completed, the milling assembly was POOH, and the drilling assembly, containing a 13-½ inch by 17-½ inch bi-center bit, was run in to drill the next hole section. This hole section was cased with 13-3/8-inch flush-joint casing

Several occurences on this expansion operation should be recognized as highlights for the first installation on this rig and/or on the expansion operation itself.

- Minimal drag occurred when the launcher entered the 16-inch subsea hanger: launcher OD was 14.750 inches, while hanger ID was 14.822 inches and drift was 14.750 inches.

- Using the mud pumps for the expansion operation worked well, enabling all operations to be performed from a central location.
- The contingency operation, utilizing jars and drill collars to initiate expansion, was successful.
- The expansion operation was smooth even with shale inside the liner, which had entered the liner while drill pipe was being tripped to pick up the jarring assembly.
- Maintaining 85 to 100 percent of liner weight on the hookload contributed to lower expansion pressures and smoother operation. The procedure also ensured the liner remained on-bottom after each stand was expanded.
- The procedure was successful to manage the pop-out effects by limiting pump rate at 1 BPM, 1,400 psi and 40 kips overpull. This resulted in minimal energy release and no surface indications being observed.

Lessons Learned. This operation identified several areas where changes could be made to either improve the efficiency of the operation or offer improvement to the system(s).

- The latchdown plug did not bump during displacement, thus no remedial action such as squeezing the cement into the formation had to be performed. Changes have been incorporated into the operational procedures to minimize the risk of this occurring, and additional modifications have been made to the bumper subs to reduce the chance of the latchdown plug hanging up. The latchdown plug has also been modified so that it can more easily traverse internal diameter changes.
- A second latchdown plug was dropped to dislodge the first one and enable it to seat. This action blocked off the rupture disks and prevented pressure communication to them; without which, the rupture disks could not be opened and conventional expansion initiated. The launcher/shoe assembly has been redesigned to accommodate contingencies for bursting rupture disks and/or opening pressure communication to the expansion assembly.

Conclusions

Ideas, conceptual designs and implied applications are valuable in the advancement of a new technology. However, until products are produced and successfully applied to significant challenges, it is merely "cute science." Over the past year, Solid Expandable Tubulars has made the leap from conception to an enabling technology in the drilling environment. November of 1999 saw the first drilling application of Solid Expandable Openhole Liners to solve a pore pressure / fracture gradient drilling challenge in the Gulf of Mexico. Since then, the use of SETs has provided operators with a cost-effective solution to solve a variety of drilling challenges. The correct application of this "tool" in the drilling "tool box" will prove successful for a myriad of drilling challenges, while increasing operators' return-on-investment.

Some of the applications outlined here have provided ample learning opportunities in both the engineering and deployment of the SET systems. This information has improved the systems themselves and their deployment, resulting in a more robust and cost-effective product.

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Fig. 1 – Early expansion mandrel used to expand Solid Expandable Tubulars (SETs)

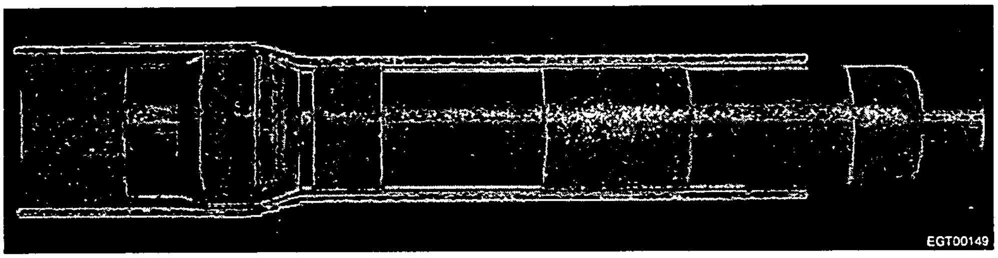

Fig. 2 – Differential pressure pumped through the inner-string

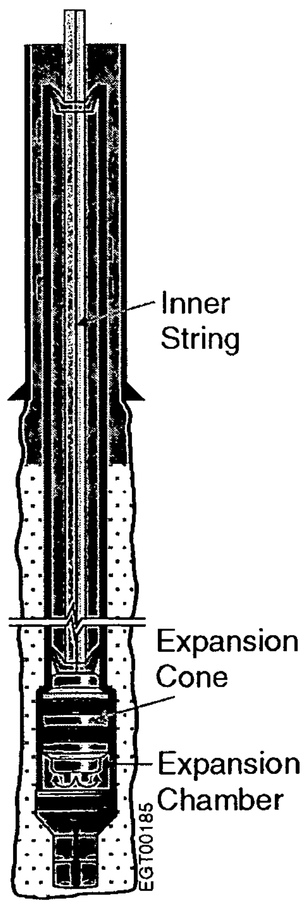

Fig. 3 – Stress/strain curve for Solid Expandable Tubulars

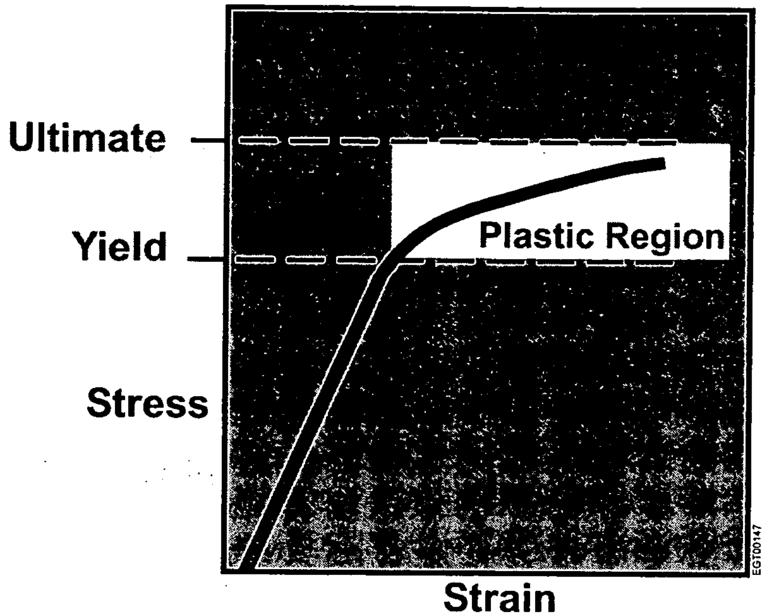

Fig. 4 – Because the launcher has a thinner wall and its outside diameter is the same as the drift of the previous string of casing, it can be tripped into the hole through the previous casing string.

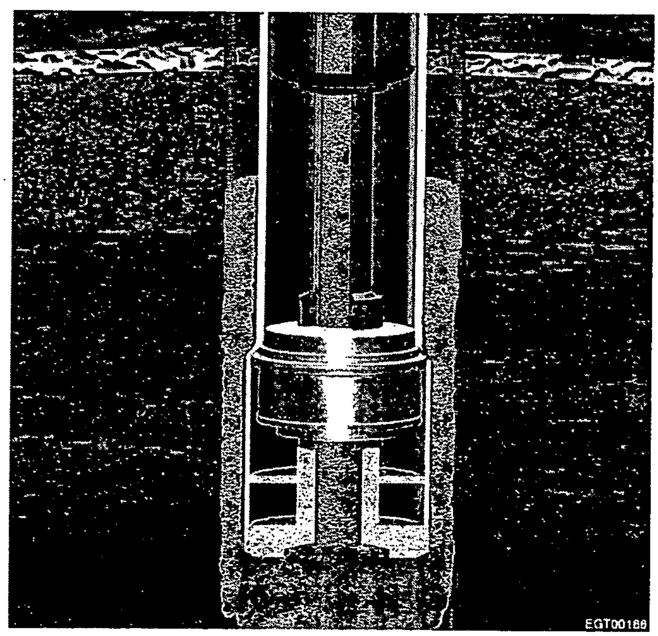

Fig. 5 – Installation sequence for Expandable Openhole Liner System

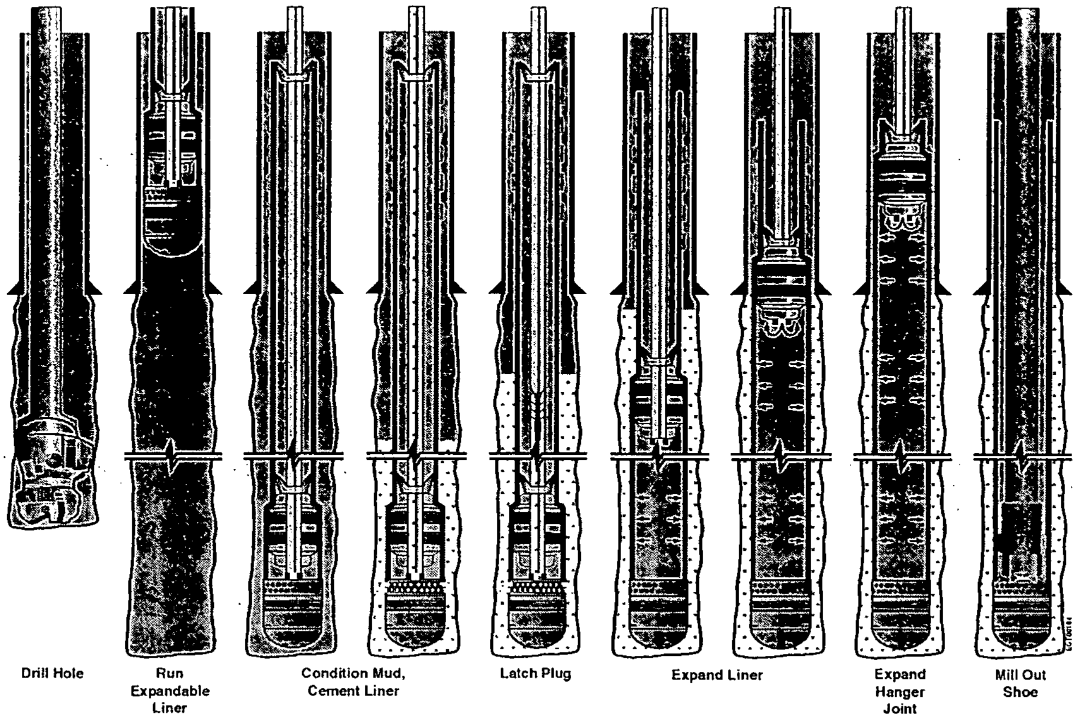

Fig. 6 – Conventional Vs. Expandable Openhole Liner well designs in a well with abnormally-pressured zones

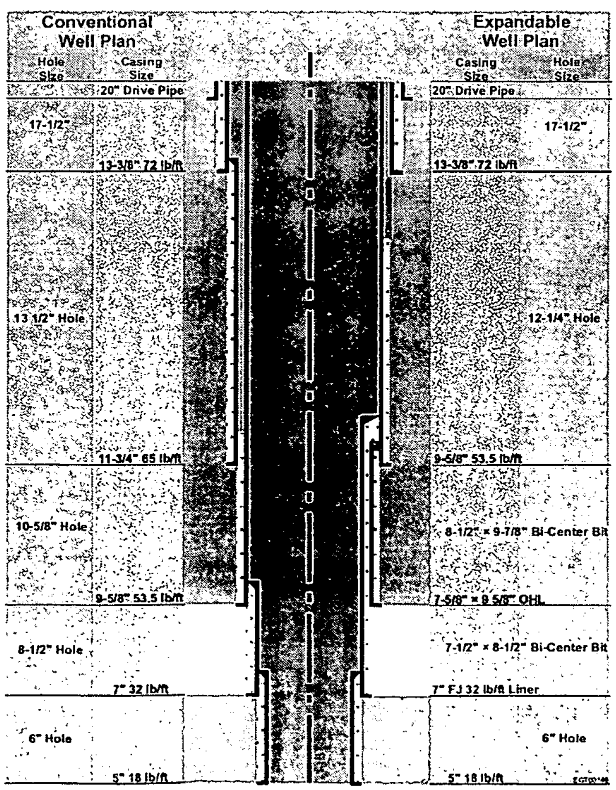

Fig. 7 – Ultra-deepwater pore pressure / frac gradient plot utilizing a Solid Expandable Tubular (SET) Openhole Liner

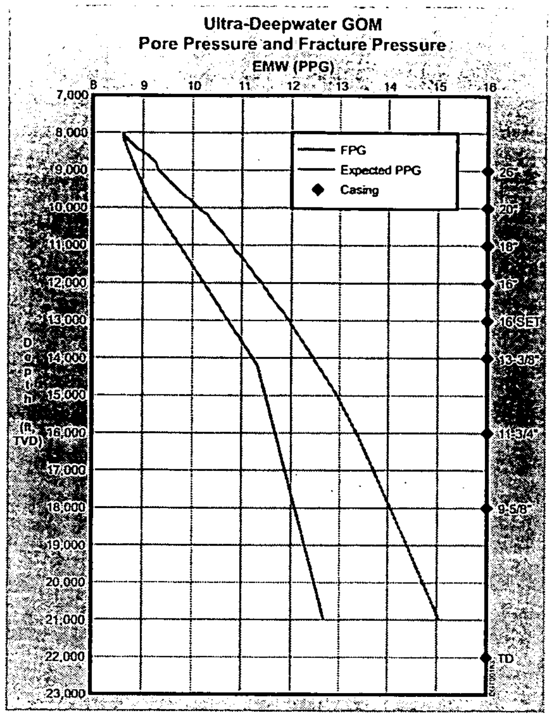

Fig. 8 - Ultra-deepwater well using a 13-3/8 inch X 16-inch SET System

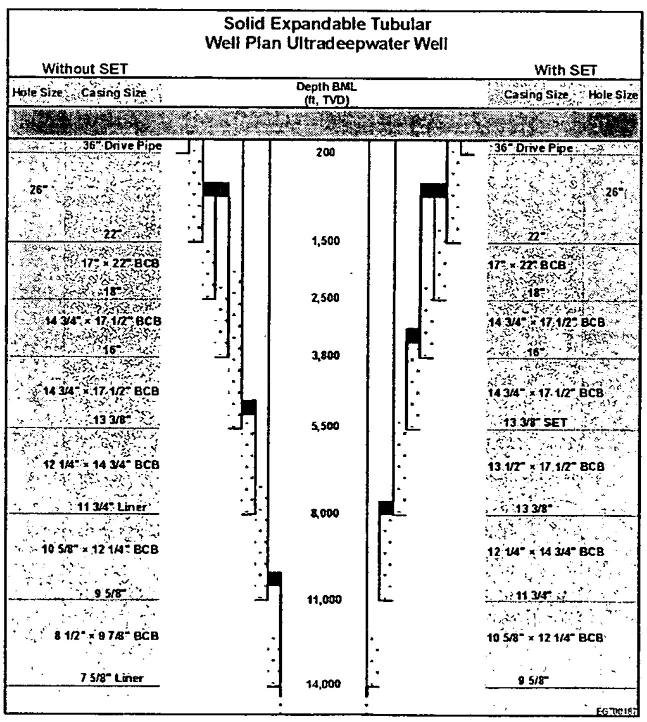

Fig. 9 – 18-3/4 inch BOP system Vs. 13-5/8 inch slender well with compact rig using SET technology

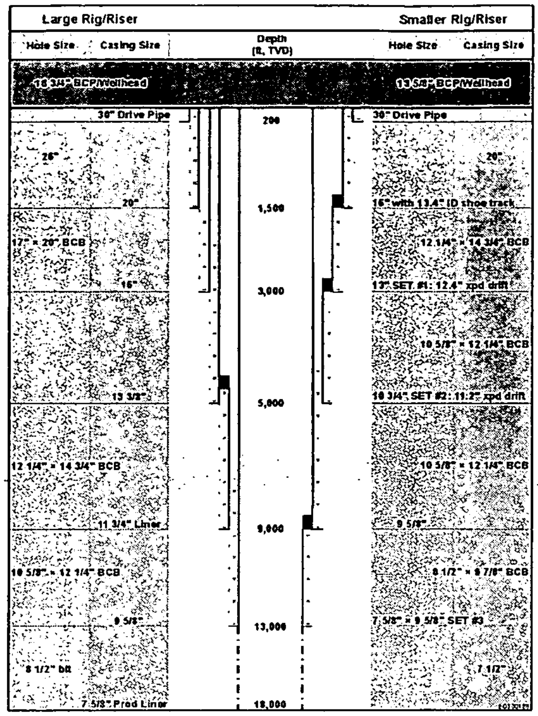

Fig. 10 – Tornado Chart illustrating savings when slender well is combined with compact rig and SET technology

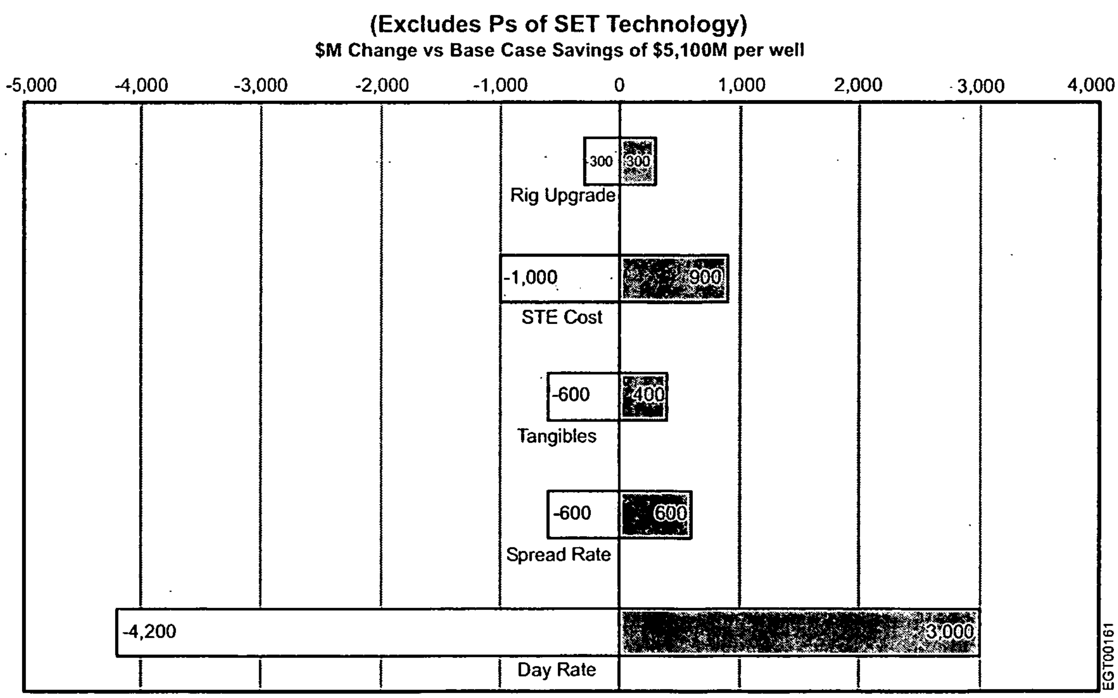

Fig. 11 – Well plan utilizing "nested" Openhole Expandable Liners

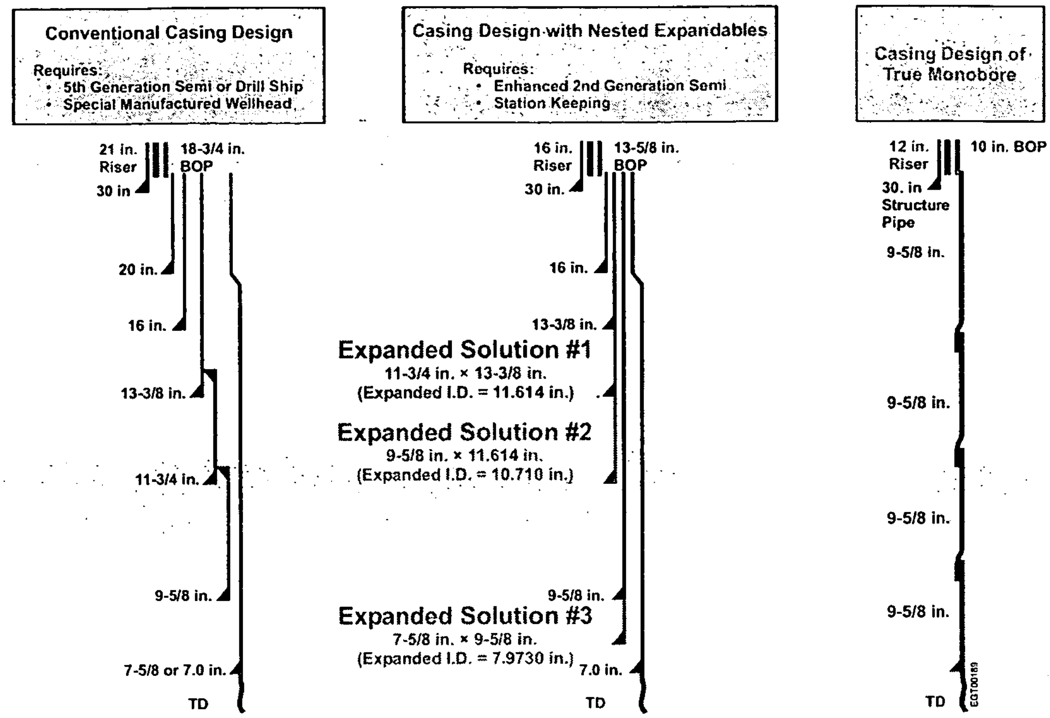

Fig. 12 – BP/Vastar, Mississippi Canyon 7-5/8 inch X 9-5/8 inch Expandable OHL installation

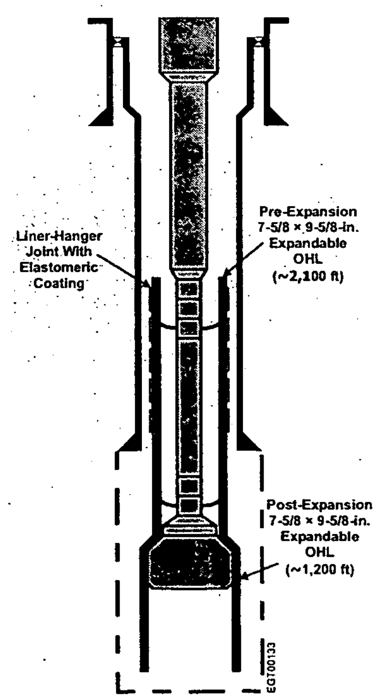

Fig. 13 - Shell/McAllen 106 6-inch X 7-5/8 inch Expandable OHL installation

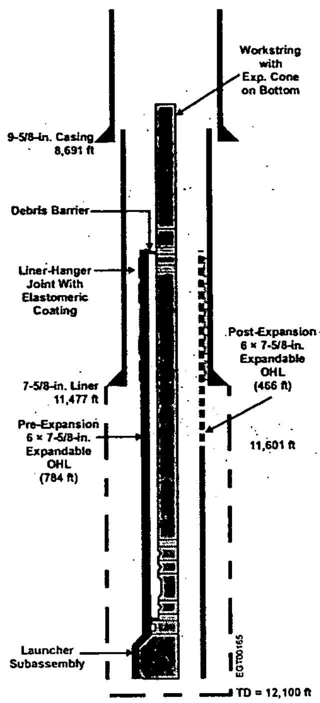

Fig. 14 – Differentially-stuck pipe/liner

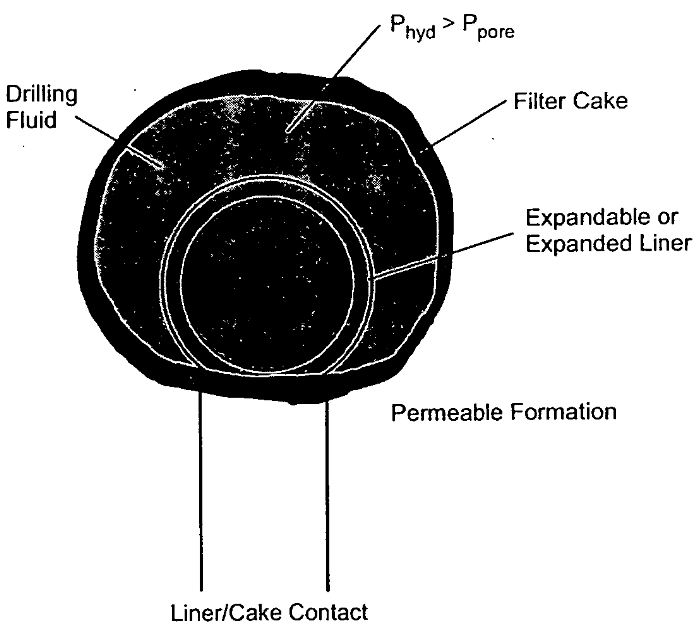

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Fig. 15 – (a) Cross-section on left depicts uniform hoop stress distribution during pipe expansion in free state, while (b) cross-section on right shows Hoop stress concentration due to expansion cone rotation under differentially-stuck condition.

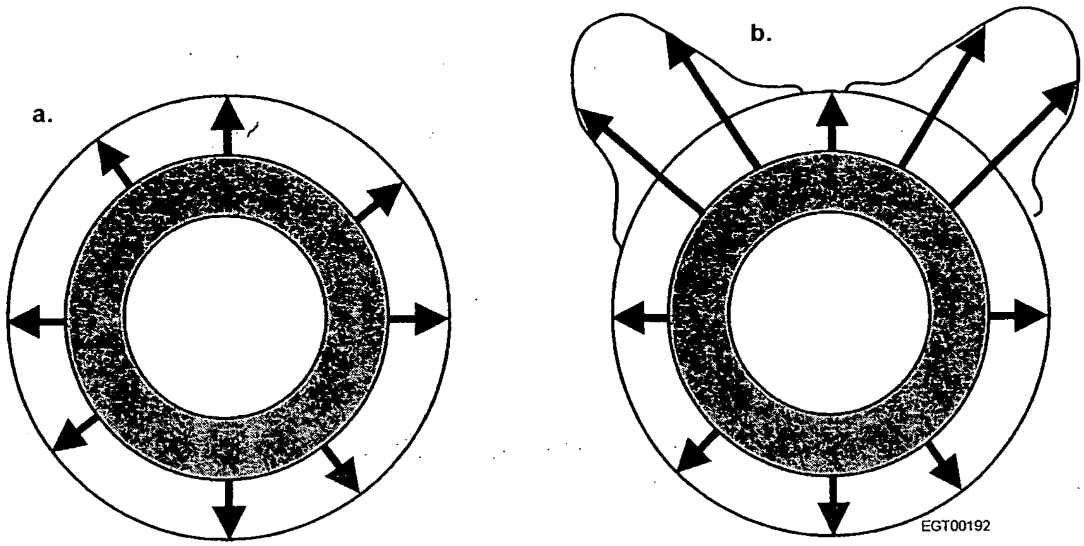

Fig. 16 – Expansion through differentially-stuck interval

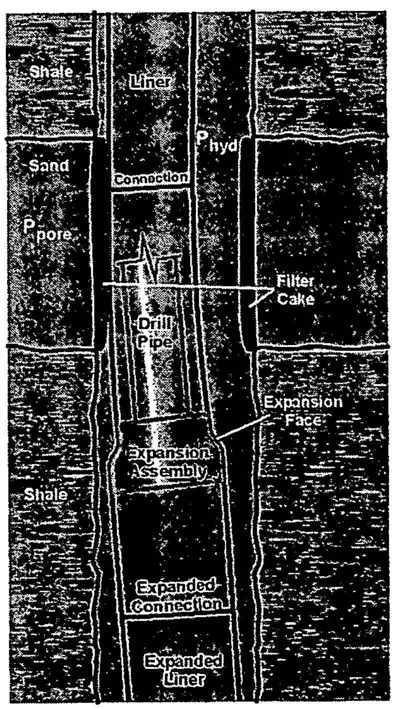

Fig. 17 – Geometrical constraints and additional loading caused by differential sticking

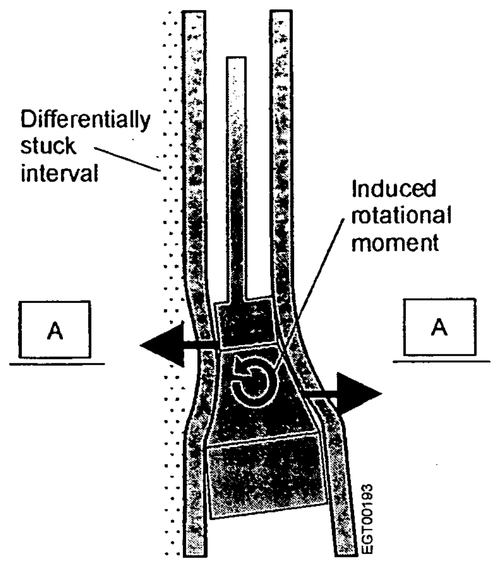

Fig. 18 – Shell/Thomas Rife 13 – 13-3/8 inch X 16-inch Expandable Openhole Liner installation